California Public Utilities Commission

Headquarters Office: 505 Van Ness Avenue, San Francisco, CA 94102

DISCUSSION ON MARKET PRICE REFERENTS (MPR)

MPR Methodologies To Determine The Long-Term Market Price Of Electricity For Use In California Renewables Portfolio Standard (RPS) Power Solicitations

Prepared by the Energy Division and the Division of Strategic Planning of the California Public Utilities Commission

In collaboration with the Renewable Energy Program of the California Energy Commission

March 22, 2004

DISCLAIMER -- Opinions, conclusions, and findings expressed in this report are those of the authors. This report does not represent the official position of the Commission until adopted by rule or decision at a Commission meeting. Commission staff would like to thank CEC collaborative staff and their contractors for comments on early drafts of this paper.

Table of Contents

Discussion of Market Price Referent (MPR) Methodologies

I. We Invite Parties to Comment On Specific MPR Methodologies

As stated in the Energy Action Plan (EAP),[1] the Commission, jointly with the California Energy Commission (CEC) and the California Power Authority (CPA) aims to reach a utility portfolio target of 20% renewable energy resources in 2010:

> "In 2002, the Governor signed the Renewable Portfolio Standard (RPS), SB 1078. This standard requires an annual increase in renewable generation equivalent to at least 1% of sales, with an aggregate goal of 20% by 2017. The state is aggressively implementing this policy, with the intention of accelerating the completion date to 2010…." (Energy Action Plan, p.5)

In furtherance of this goal, we open the discussion on specific Market Price Referent (MPR) methodologies for use in determining proxies for the long-term market prices of various electricity products. MPRs will be used to establish the maximum price at which an RPS-obligated entity can be compelled to purchase renewable energy, up to its Annual Procurement Target (APT), and to determine whether Supplemental Energy Payments (SEPs) [2] are applicable to bids that result from RPS solicitations.[3] We focus and invite parties to comment on the following inputs necessary to determine MPRs for baseload and peaking proxy plants:

- Capital Cost ($/kW),
- Capital Cost Adder for Local Land and Permit Costs ($/kW),[4]
- Capital Cost Adder for Gen-tie costs (i.e., the cost of direct assignment transmission facilities) ($/kW)

[1] The Energy Action Plan (EAP) and related documents are available on the Commission's website, www.cpuc.ca.gov/static/industry/electric/energy+action+plan/index.htm

[2] The market price referent structure does not determine whether renewable bidders win or lose, it merely distinguishes when SEPs apply. Bids that are priced lower than the applicable MPR are not eligible for SEPs; bids that are priced above the MPR are eligible for SEPs according to guidelines established by the California Energy Commission. Draft Guidebooks are available on the Energy Commission website at: www.energy.ca.gov/portfolio/documents.index.html.

[3] RPS-obligated entities are able to procure renewable power at prices above the MPR, should they so propose and the Commission grant approval. A Commission-established incentive structure may be appropriate to foster the desired level of renewable procurement.

[4] Regarding proposed Local Land and Permit Costs ($/kW), parties may choose to present these costs as a separate line item in the form of a Capital Cost Adder, or parties may elect to present only Capital Cost figures that already include Local Land and Permit Costs. In the event parties present separate Local Land and Permit Costs, we highly encourage parties to express these estimates in units of $/kW so that an 'all-in' Capital Cost can be quickly and easily determined by adding the two estimates, or ranges thereof.

- Capital Recovery Factor,
- Capacity Factor (%)
- Fixed O&M Costs ($/kW/yr),
- Gas Fuel Costs ($/MMBtu),
- Hedging Costs ($/MMBtu),
- Heat Rate (Btu/kWh),
- Variable O&M Costs ($/kWh), including necessary pollution offsets,
- Any other adders or adjustments to the above components necessary to calculate complete, stand-alone MPRs.

Parties should file pre-workshop comments by Monday, April 5, 2004, which should include parties' best working estimates on the above proxy plant inputs. These comments may become part of the record in the future. MPR workshops will be held Thursday, April 15, 2004 and Tuesday, April 20, 2004 in San Francisco. We will assign one volunteering party the task of compiling a post-workshop issues matrix to be circulated to all parties by Wednesday, April 28, 2004.

The purpose of the MPR workshops will be to agree on MPR methodologies and associated inputs, for use in the first solicitation this year. Prior to subsequent solicitations under the RPS the Commission may revisit the MPR calculation methodology as needed. The priority for this year, in the staff view, is an MPR that meets the immediate needs of the RPS legislation, previous Commission orders, and the first year of a multi-year program to stimulate substantial technological change towards achievement of the RPS.

A. Background

D.02-10-062 (Ordering Paragraph 6) called "all interested parties [to] file a proposed procedural process and schedule to implement Senate Bill 1078 on January 6, 2003 and reply comments on January 13, 2003." A majority of the parties addressed MPR issues, which are identified in Appendix A, "Parties' January 2003 Filings on MPR Issues."

On April 1, 2003, parties filed testimony in the Procurement Rulemaking (R.) 01-10-024 on issues associated with the implementation of the RPS program as set forth in Public Utilities Code 399.11 through 399.16. Briefly, those issues were on establishing (1) a process for determining market prices, (2) a process that provides criteria for the rank-ordering and selection of least-cost and best-fit renewable resources, (3) flexible rules for compliance, and (4) standard terms and conditions to be used by all utilities in contracting for eligible renewable energy resources.

The Commission directed interested parties to serve testimony concerning the first three items and to serve a “supplement” concerning the fourth. Similarly, a majority of the parties addressed MPR issues, as identified in Appendix B, "Parties' April 2003 Testimony on MPR Issues."

The California RPS program[5] calls for the Commission to "establish a methodology to determine the market price of electricity for terms corresponding to the length of contracts with renewable generators"[6]. The "market price" must reflect the long-term market price of electricity a utility would need to purchase to meet its capacity and energy needs from conventional fossil fuel resources instead of the renewable resources proposed under the RPS bidding process. The MPR developed by the Commission must consider "the value of different products including baseload, peaking, and as-available output."[7]

In June 2003, the Commission issued Decision (D.) 03-06-071, which provided additional guidance on these issues. We consider this guidance here as we prepare for a workshop on how to specifically determine the necessary MPRs. Some parties suggested that the Commission give significant weight to existing, long-term power contracts in establishing the long-term market price of electricity. However, D.03-06-071 states:

> "While theoretically such contracts would provide a simple and relatively accurate measure of market price, in practice there needs to be a usable quantity of contracts meeting the statutory requirements, and it is not clear that such contracts presently exist. The record does not indicate that there are contracts sufficient in number or comparability to provide a basis for setting a market price. (See, e.g., UCS Opening Brief, p. 6, citing to testimony of TURN and CEERT; Solargenix Opening Brief, p. 6.) Accordingly, while the Commission will certainly consider any such contracts in determining a market price, we cannot rely significantly upon them at this time." (D.03-06-071, p.16)

D.03-06-071 opted to focus on the use of proxy plant calculations in order to estimate the long-term market price of electricity. D.03-06-071 adopted two referent approaches: one for baseload resources, based on a new combined cycle plant proxy value, and one for peaking resources, based on a new combustion turbine proxy value.

A number of parties had recommended using the CEC's draft report on the *Comparative Cost of California Central Station Electricity Generation Technologies* (referred to herein as "the CEC Cost of Generation Report," and as

[5] Enacted by Senate Bill 1078 (Sher), Chapter 516, Statutes of 2002

[6] Pub. Util. Code Section 399.15(c)

[7] Pub. Util. Code Section 399.15(c)(3)

"the CEC report" in quotations from D.03-06-071) as a starting point.[8] D.03-06-071 referred specifically to the report in three instances:

> "While the methodology and/or data used in the CEC report may need some adjustments or modifications, the CEC report provides a reasonable and objective starting point." (p 20).
>
> "Collaborative Staff will examine the CEC report, consider the adjustments and modifications recommended by the parties in this proceeding, and will issue a report containing the Collaborative Staff's recommendations. Following issuance of that report, Collaborative Staff will conduct workshops to further refine the details of the approach to be used." (p.20)
>
> "We note that the CEC report does not include the cost of direct assignment transmission facilities.[9] As the cost of these facilities is a direct cost to both a proxy plant and to participating renewable generators, it should be reflected in the MPR." (p.20)

The most recent version of the CEC Cost of Generation Report was finalized in August 2003, and reflects consideration of many of the comments parties made in the RPS proceeding at the Commission. However, sufficient time has passed since it was prepared that many assumptions, such as gas price forecasts, should be reconsidered as we proceed with the development of MPRs. In addition, the report makes clear that some aspects of proxy plant economics, such as the direct assignment transmission facility costs noted above, are not included in the report's methodology. The report states:

> "This report is intended to provide a basic understanding some of the fundamental attributes that are generally considered when evaluating the cost of building and operating different electricity generation technology resources. But these costs do not reflect the total costs to consumers of adding these technologies to a resource portfolio. The technology costs in this report are not site specific. If a developer builds a specific power plant at a specific location, the cost of siting that plant at that specific location

[8] The CEC's August 2003 *Comparative Cost of California Central Station Electricity Generation Technologies* report, www.energy.ca.gov/reports/2003-08-08_100-03-001.PDF, is the most recent version of this report. Note that prior to the table of contents in the August 2003, there are three pages of errata to the earlier June 5, 2003 Final Staff Report of the same name. The August 2003 report was prepared in support of the CEC's *Integrated Energy Policy Report (IEPR) Subsidiary Volume: Electricity And Natural Gas Assessment Report*, see p.10 for citation, www.energy.ca.gov/2003_energypolicy/index.html.

[9] These facilities, also referred to as "gen ties," serve to connect the generation facility to the grid, and for siting purposes are typically considered a component of the generation facility. Direct assignment facilities also receive different FERC ratemaking treatment than network upgrades, which are typically sited by the Commission as a utility transmission facility.

> must be considered. Some projects may require radial transmission additions, fuel delivery, system upgrades or environmental mitigation expenses." (p.1)
>
> "This levelized cost analysis does not capture all of the system, environmental or other relevant attributes that would typically be examined by a portfolio manager when conducting a comprehensive "comparative value analysis" of a variety of competing resource options. A portfolio analysis will vary depending on the particular criteria and measurement goals of each study. …. For example, some projects may also require radial transmission additions, fuel delivery, system upgrades or environmental mitigation expenses." (p.1)

Collaborative Staff has reviewed the CEC Cost of Generation Report in the course of preparing this discussion paper.

Bids are to be selected in the RPS bidding process according to least-cost and best-fit rankings,[10] and winning bidders are eligible to receive SEPs for any positive difference between their bid price and the MPR, although the terms for use of SEP funds must be clearly set forth in the Request For Proposal (RFP). The utilities may propose RPS contracts[11] at prices above the MPR, but specific Commission authorization of these contracts will be required.[12]

In some cases, bidders may have previously won an award for Public Goods Charge (PGC) funding from Senate Bill 90 (SB 90, Sher, Statutes of 1997, Chapter 905). Under SB 90, the Energy Commission provided conditional funding awards to new renewable facilities in the form of production incentives paid on a cents per kilowatt hour basis once facilities begin operation. The Energy Commission pays these production incentives for up to the first five years of project operation.

A bidder with an SB 90 award may elect to keep their award and submit a bid that reflects that choice. Alternately, eligible bidders may choose to forfeit their SB 90 award and compete for Supplemental Energy Payments (SEPs) funded under the authority of Senate Bill 1078 (SB 1078, Sher, Statutes of 2002, Chapter 516) and Senate Bill 1038 (SB 1038, Sher, Statutes of 2002, Chapter 515). SEPs are funded through the public goods charge

[10] See discussion in D.03-06-071, beginning at p. 27

[11] The actual power purchase agreements may specify separate capacity and energy payments, which must be translated to an all-in price for purposes of gauging a utility's cost responsibility in the contract. "All-in" means that the referent does not differentiate the value of capacity and energy, and has units of dollars per MWh or cents per kWh.

[12] This is an important point of flexibility in the RPS program, given the potentially limited supply of Supplemental Energy Payments and the accelerated RPS goals adopted in the Joint Agency Energy Action Plan.

and will be available from the Energy Commission to cover the appropriate above-market costs of renewable resources selected by retail sellers to fulfill their RPS obligations.[13]

As parties are aware, the process for developing transmission cost adders to be applied to RPS bids is under way in Investigation (I.) 00-11-001. The results of this process will be available in time for the adders to be included in the responses by renewable generators to the first RPS bid. This bifurcated procedure is necessitated by Section 399.15(a)(2), which requires that transmission upgrade costs be calculated separately and not be eligible for Supplemental Energy Payments from the CEC.

B. RPS Overview

The California RPS program was established when Senate Bill (SB) 1078 was signed by the Governor on September 12, 2002 and became effective January 1, 2003. The RPS program is codified in the Public Utilities Code as Part 1 of the Public Utilities Act in Chapter 2.3 Electrical Restructuring, Article 16. California Renewables Portfolio Standard Program, Section 399.11 through 399.16.[14] These code sections are briefly described here:

- Section 399.11: Purpose and Goals of the RPS Program.
- Section 399.12: Terms and Definitions.
- Section 399.13: CEC tasks and responsibilities.
- Section 399.14: CPUC tasks and responsibilities.
- Section 399.15: CPUC-CEC tasks and responsibilities.
- Section 399.16: Criteria for out-of-state generators seeking eligible renewable energy resource status.

In preparation for an upcoming MPR workshop, we focus primarily on the following code sections:

[13] California Energy Commission, Renewables Portfolio Standard: Decision on Phase 2 Implementation Issues, Commission Report, October 2003, publication number 500-03-049F, http://www.energy.ca.gov/portfolio/documents/2003-09-29_hearing/2003-10-21_COMSN_RPRT_PHSII.PDF

[14] Public Utilities Code online at www.leginfo.ca.gov under "California Law." RPS Sections: http://www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=00001-01000&file=399.11-399.16

Section 399.15 (c) The commission shall establish a methodology to determine the market price of electricity for terms corresponding to the length of contracts with renewable generators, in consideration of the following:

(1) The long-term market price of electricity for fixed price contracts, determined pursuant to the electrical corporation's general procurement activities as authorized by the commission.

(2) The long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities.

(3) The value of different products including baseload, peaking, and as-available output.

Section 399.14 (a) (2) Not later than six months after the effective date of this section, the commission shall adopt, by rule, for all electrical corporations, all of the following:

(A) A process for determining market prices pursuant to subdivision (c) of Section 399.15. The commission shall make specific determinations of market prices after the closing date of a competitive solicitation conducted by an electrical corporation for eligible renewable energy resources. In order to ensure that the market price established by the commission pursuant to subdivision (c) of Section 399.15 does not influence the amount of a bid submitted through the competitive solicitation in a manner that would increase the amount ratepayers are obligated to pay for renewable energy, and in order to ensure that the bid price does not influence the establishment of a market price, the electrical corporation shall not transmit or share the results of any competitive solicitation for eligible renewable energy resources until the commission has established market prices pursuant to subdivision (c) of Section 399.15.

Section 399.14 (f) Procurement and administrative costs associated with long-term contracts entered into by an electrical corporation for eligible renewable resources, at or below the market price determined by the commission pursuant to subdivision (c) of Section 399.15, shall be deemed reasonable per se, and shall be recoverable in rates.

II. Six "All-In" MPRs Must Be Calculated

D.03-06-071 adopted "a proxy plant methodology for calculating the market price referent, using a combined cycle proxy plant for the baseload product and a combustion turbine proxy plant for the peaking product" (Ordering Paragraph 6). The decision also determined that the "market price referent will be calculated as an all-in cost, with an exception for as-available capacity" (OP 10). Section 399.14(a)(4) states that utility procurement plans shall include "direction to respondent bidders to offer prices for 10-, 15-, and 20-year contract terms." D.03-06-071 also stated “utilities should seek bids for 10, 15, and 20-year products” (p. 57).

Therefore, one MPR must be calculated for a baseload product and another MPR for a peaking product. These two MPRs must be adjusted for contract terms of 10, 15, and 20 years. Thus, six "All-In" Market Price Referents (MPRs) must be calculated.

Table 1
Six "All-In" Market Price Referents (MPRs)
Must Be Calculated

Product Type	**10-year $/kWh**	**15-year $/kWh**	**20-year $/kWh**
Baseload MPR	To be determined (Tbd)	Tbd	Tbd
Peaking MPR	Tbd	Tbd	Tbd

A. As-Available Output

D.03-06-071 noted that the valuation of "As-Available Output" as required under Section 399.15(c)(3) may not be as easily addressed via a proxy plant calculation:

> "As-available (also referred to as intermittent) is a somewhat different creature than baseload and peaking [products]. While baseload and peaking are relatively firm sources of power, differentiated by the type of load they serve and the times of the day or year they operate, an as-available resource is less firm, and may or may not operate at a particular time of the day or year. Some as-available resources may operate at times that correspond to

> daily or yearly peaks, while others may not. **Accordingly, it is difficult, if not impossible, to use a proxy plant for determining the value of as-available output**."
>
> "If sufficient and appropriate long-term fixed price contracts (as described in subsection (1)) for as-available products existed, then it would be possible to use those contracts to determine the market price for as-available products. We do not have evidence of contracts that are usable for this purpose. To the extent such contracts become available, we will consider them."
> (D.03-06-071, p.19-20, emphasis added)

D.03-06-071 determined that "the applicable market price referent for an as-available resource will be either the baseload or peaking referent, depending on which product that resource bids. Thus, we will not establish separate MPRs for as-available output (intermittent) products at this time.

B. As-Available Capacity

D.03-06-071 gave bidders the option to either use Commission-approved as-available capacity values in their bids, or the flexibility of using "an all-in energy and capacity price [as] determined by the bidder." This was set forth in the ordering paragraphs of the decision:

10. "The market price referent will be calculated as an all-in cost, with an exception for as-available capacity."
11. "The Commission will establish the value of as-available capacity, which as-available **<u>bidders can choose</u>** to incorporate into their bids."
12. "Bidders will submit either an energy price and a Commission-approved capacity price, or an all-in energy and capacity price determined by the bidder, **<u>depending on</u>** the product and the **<u>discretion of the bidder</u>**."

Subsequent to D.03-06-071, the Commission issued D.03-12-062 which, among other things, stated the Commission's intent[15] to modify existing as-available capacity values, applicable to some QFs contracts. D.03-12-062 called for staff to draft an "Order Instituting Rulemaking (OIR) that will examine and propose appropriate modifications to the SRAC methodology" (*Id*., p.58). Because D.03-06-071 did not require bidders to use Commission-approved capacity values in their

[15] "All three utilities contend that revision of the current SRAC methodologies for determining QF energy and capacity payments is needed. For many years now, SRAC has been approximated through time-differentiated energy prices (set once a month) and time-differentiated capacity prices (set annually). However, there is evidence on the record in this proceeding that indicates that the current SRAC energy pricing methodology has yielded prices in excess of spot market prices for significant periods of time." (D.03-12-062, 56)

bids, the establishment of separate as-available capacity values is not a requirement for RPS power solicitations to proceed. In any event, this issue will be considered as part of the Least Cost/Best Fit ranking process and will be taken up in that context, not as part of the development of the MPR methodology.

C. Time-Of-Delivery Considerations

The development of a potentially infinite range of time-differentiated MPRs is beyond the scope the RPS requirements. At the same time it is important to recognize the value of renewable generation at different times of the day and year. For example, SCE has incorporated Seasonal and Time-Of-Delivery (TOD) factors into its 2003 Renewable Resource Solicitation, which we encourage parties to consider in advance of the workshop.[16]

III. Specific and Complete MPR Calculations Must Be Presented

To date, the Commission has not adopted specific MPR calculations. No specific calculations or methodologies were established or proposed in D.03-06-071. With regard to calculating MPRs using proxy power plant estimates, parties filing testimony on April 1, 2003, as shown in Table 1 above, either (1) presented and discussed only a subset of the total number of components relevant to calculating an MPR, or (2) provided illustrative (in some cases very detailed) overviews of how MPR calculations might be done (e.g. ORA, TURN, and CEERT). We now need to present and discuss complete stand-alone MPR methodologies for Commission consideration.

We propose for discussion the MPR calculations set forth in Table 2, Proposed Market Price Referent (MPR) Proxy Plant Calculation Methodology.[17]

[16] See SCE's Revenue Calculator for use in its 2003 Renewable Resource Solicitation, www.sce.com/sc3/005_regul_info/005i_qualifying_facilities/RR_RFP2003.htm.

[17] The methodology utilized in Table 2 of this report is based on the EPRI/TAG methodology, as applied by the California Interagency Green Accounting Working Group (IGAWG), as reported in a June 2002 report entitled "Comprehensive California Report on a Renewable Energy Investment Plan." The IGAWG was established in 2001 by the Office of Planning and Research (Dr. Woodrow W. Clark II, Senior Policy Advisor) and the State and Consumer Services Agency (Arnie Sowell, Deputy Secretary). See specifically, "Table A.1a: Calculations and Assumptions for Computing Costs of Energy Production" in Appendix A, "Relative Costs and Benefits of Electricity Generation Resource Investment Options."

Table 2
Proposed Market Price Referent (MPR)
Proxy Plant Calculations
EPRI/TAG Methodology

= Inputs

		Baseline Product	Data Source on Baseline	Peaking Product	Data Source on Peaking
A. Proxy Plant Characteristics					
(1)	Plant Capacity (MW)	750	CEC Report, Appendix C, Table C-2	120	CEC Report, Appendix D, Table D-2
(2)	Capital Cost ($/kW)	$650	TURN, p.11. (Low-end of range, $675 to $850)	$475	CEC Report, Appendix D, Table D-10
(3)	Capital Recovery Factor (Calculated)	0.098	Energy Division: 20 years at 7.5%.	0.098	Energy Division: 20 years at 7.5%.
(4)	Capacity Factor	92%	TURN, p.13	10%	Note: CEC Report, Appendix D, Table D-9 uses 9.4%
(5)	Fixed O&M Costs ($/kW/yr)	$9.00	Rough Estimate	$9.81	CEC Report, Appendix D, Table D-9
(6)	Gas Fuel Costs ($/MMBtu)	$4.880	ORA, p.6	$4.880	ORA, p.6
(6a)	Hedging Costs ($/MMBtu)	$0.450	UCS, p.14	n.a.	Hedging costs maybe negligible for peaking fuel supply.
(7)	Heat Rate (Btu/kWh)	7,400	CalWEA, p.3	9,300	CEC Report, Appendix D, Table D-5
B. Capital Cost Recovery					
(8)	Installed Capital Costs ($ millions) (1) x (2) ÷ 1,000	$488	Calculated figure.	$57	Calculated figure.
(9)	Capital Costs Recovered per Year ($/kW/Year) (2) x (3)	$64	Calculated figure.	$47	Calculated figure.
(10)	Capital Costs Recovered per kWh ($/kWh) (9) ÷ [(4) x 8760 hrs/yr]	$0.0079	Calculated figure.	$0.0532	Calculated figure.
C. Operational Costs					
(11)	Fixed O&M Cost per kWh ($/kWh) (5) ÷ [(4) x 8760 hrs/yr]	$0.0011	Calculated figure.	$0.0112	Calculated figure.
(13)	Variable O&M Costs ($/kWh)	$0.0052	Rough Estimate	$0.0052	Rough Estimate
D. Fuel and Other Costs					
(12)	Fuel Costs per kWh ($/kWh) (6) x (7) ÷ 1,000,000	$0.0361	Calculated figure.	$0.0454	Calculated figure.
(14)	Hedging Value ($/kWh) (6a) x (7) ÷ 1,000,000	$0.00333	Calculated figure.	-	Calculated figure.
(15)	**Illustrative Market Price Referents (MPRs)** Total Cost of Production ($/kWh) (10) + (11) + (12) + (13) + (14)	**$0.0537**	Calculated figure.	**$0.1150**	Calculated figure.

Note: the methodology proposed here includes the categories of costs listed in column one of the table. It does not include the identified values, which are included as a reference, or the data sources listed in column three.

Parties should consider and be prepared to comment on any important differences between the approach presented here and that contained in the CEC Cost of Generation Report. MPR components such as permitting costs, emissions offsets and gen-tie costs, not included in this table, must also be incorporated into the final MPR methodology.

The purpose of these calculations is to focus discussion and narrow the debate. Parties wishing to engage in a greater level of detail are asked to first provide their working estimates of each component to the calculation set forth in Table 2; adding or removing components is acceptable if necessary to clearly describe a position.

Parties are welcome to provide complete alternate methodologies, clearly identifying their own inputs (or ranges thereof) to the calculations presented. The added benefit of utilizing a complete or stand-alone MPR methodology at this point is that parties will be compelled to set forth a position on each component, and they will also be able to see the final result of their various assumptions in the form of actual market price referent estimates.

The proxy plant referents should account for standard cost inputs and associated factors. The CEC Comparative Generation report provides the values for most of these factors (see Appendices C and D of the CEC Comparative Generation report).

A. Capital Cost and Financing Parameters

D.03-06-071 found that the CEC's Cost of Generation Report provides a reasonable and objective starting point for developing the appropriate costs associated with the proxy plants, although adjustments would be necessary.

> "In developing the appropriate costs associated with the relevant proxy plants, a number of parties recommend using the CEC's draft staff report *Comparative Cost of California Central Station Electricity Generation Technologies* as a starting point. (See, e.g., PG&E Reply Brief, p.36; CEERT, Ex. RPS–1, p. II-6; Solargenix, Reply Brief, p. 12.) While the methodology and/or data used in the CEC report may need some adjustments or modifications, the CEC report provides a reasonable and objective starting point." (D.03-06-071, p.20)

For purposes of illustration, we reference a number of the filings that were submitted in January and April 2003. It can be very difficult to obtain reliable information about the actual installed costs of individual power generation projects and care should be taken to ensure that publicly available data results in an "apples-to-apples" comparison among projects. Some figures can be early-stage development estimates of construction costs that may not include permitting costs, costs of emission credits, development costs, owner overheads, etc. These amounts can also exclude finance related costs such as interest during construction or Allowance for Funds Used During Construction (AFUDC). Actual project costs (excluding finance related costs) can actually be 20% to 40% greater than self-reported amounts publicly quoted, like those on the CEC website -- verification of capital cost information is not part of the CEC licensing process. In addition, there may be a tendency to under estimate cost projections in the early stages of development (i.e. when submitting permit applications) in order to (i) seek to generate competitive bids from construction contractors, and (ii) seek to reduce property tax assessments of projects.

A potentially more reliable source for actual cost of completed projects is from information provided to project lenders (and their advisors) in conjunction with financing of individual projects. Although not all projects are financed, a sufficiently large number have been financed in recent years, which can provide a reliable data-base for completed project costs.

1. Construction Costs

TURN proposes a range of $675/kW to $850/kW. TURN considers the CEC figure of $594/kW to be too low because it does not include urban offsets (or any offsets for that matter)" (TURN Testimony, Marcus, April 1, 2003, p.11). The $594/kW figure is $616/kW in the June and August 2003 versions of the CEC Cost of Generation Report (Table C-10 Cost Summary, p.C-3), which is still below the range suggested by TURN.

2. Direct Assignment Transmission Facilities (Gen-tie or Gentie)

With regard to direct assignment transmission facility (generation intertie or "gentie" or "gen-tie"), D.03-06-071 stated that:

> "We note that the CEC report does not include the cost of direct assignment transmission facilities.[18] As the cost of these facilities is a direct cost to both a proxy plant and to participating renewable generators, it should be reflected in the MPR." (D.03-06-071, p.20)

We will need to develop the gentie component of the MPR before presenting the methodology for Commission consideration. We would prefer that parties present gentie costs as a capital cost, in dollars per kilowatt ($/kW).

3. Financial Parameters and Capital Recovery Factors

Parties' April 2003 testimony provides, in some cases, extremely detailed information on financial parameters associated with large power plant projects.

[18] These facilities, also referred to as "gen ties," serve to connect the generation facility to the grid, and for siting purposes are typically considered a component of the generation facility. Direct assignment facilities also receive different FERC ratemaking treatment than network upgrades, which are typically sited by the Commission as a utility transmission facility.

This level of detail would be most useful when used in support of a recommended value that is actually part of a specific MPR calculation.

TURN, in its January 6, 2003 comments, noted the use of Capital Recovery Factors to account for a number of financial variables (TURN, Appendix A on "Data For Estimation Of Combined Cycle Generation Cost," p.32-33). TURN defined the CRF as follows:

> "Capital Recovery Factor: Function of return on equity and debt, capital structure, term of the loan, life of the plant, tax depreciation, income and property taxes (to be analyzed using a fixed charge rate or cash flow model)."

Consider the following Capital Recovery Factor (CRF) estimates as calculated in MS-Excel using the PMT (payment) function, which calculates the payment for a loan based on constant payments and a constant interest rate, as shown for a range of values in the table below:

Table 3
CAPITAL RECOVERY FACTORS (CRF)

Cost of Capital (A)	**$/kW** (B)	**Years** (C)	**$/kW-year** (D) = PMT(A,C,B)	**CRF** (F) = D ÷ A
12.5%	$650	20	$89.76	0.138
11.6%	$650	20	$85.00	0.131
10.0%	$650	20	$76.35	0.117
7.5%	$650	20	$63.76	0.098
5.0%	$650	20	$52.16	0.080
12.5%	$650	15	$98.00	0.151
10.0%	$650	15	$85.46	0.131
7.5%	$650	15	$73.64	0.113
5.0%	$650	15	$62.62	0.096
12.5%	$650	10	$117.40	0.181
10.0%	$650	10	$105.78	0.163
7.5%	$650	10	$94.70	0.146
5.0%	$650	10	$84.18	0.130

B. Operation and Maintenance (O&M) Costs

Estimating fixed Operation and Maintenance (O&M) costs and variable O&M costs can be difficult. TURN notes at page 11 that, "there is a wide divergence of opinion on the calculation of O&M costs and the split between fixed and variable O&M in various published sources." A number of the parties that filed testimony provided estimates and commentary. Not all parties provided complete estimates. For example, CalWEA only provided an estimate for variable O&M of $4/MWh, but no estimate for fixed O&M.

C. Proxy Plant Heat Rates

D.03-06-071 states "we are going to use representative statewide numbers for factors such as heat rate and line losses" (p.21). For example, regarding a baseload MPR, the "TURN/SDG&E Joint Principles on the Implementation of SB 1078" recommend using "heat rate 5% above baseload new and clean levels to reflect real world inefficiencies,"[19] (p.3) and state that an MPR for a peaking resource "should be calculated using a similar methodology used for baseload with the following exceptions: (a) use of combustion turbine cost estimates, (b) adjustment for typical new CT capacity factors (consistent with peaking operation) and heat rates" (*Id*, p.4). The CEC Comparative Generation report uses 7,100 Btu/kWh for baseload, 9,300 Btu/kWh peaking. For similar reasons, CalWEA recommends using 7,400 Btu/kWh. TURN recommends using 10,000 Btu/kWh for peaking plant, the guaranteed heat rate in some CDWR peaking contracts."

D. Other Cost Components

Other cost components can be added to the MPR calculation, such as emission offsets. ORA recommends the addition of "externality mitigation costs" of $0.05/kWh (ORA Testimony, p.6). ORA's additional costs cover more than just emissions and also include water and land impacts (*Id*., Appendix A). We do not include such additional costs in the MPR calculations in Table 2, although the Commission has adopted their inclusion in the MPR in D.03-06-071 at p.21. We will need to develop the offset cost component of the MPR before the methodology can be considered final.

[19] Startups and ramping from outages, partial forced outages, degradation between overhauls, and inefficiency due to warmer temperature than ISO

IV. Location-Specific Referents May Not Be Practical

With regard to the potential use of location-specific MPRs, D.03-06-071 stated "We will only use location-specific costs when those costs have already been specifically quantified for a particular geographic region, such as the cost of emissions offsets" (D.03-06-071, p.21). The decision sought to avoid "a potentially infinite number of market price referents, one for each project location and configuration [which…] would render the market price referent far from transparent, and would also be both cumbersome and contentious, with the assumptions for each project a potential source of litigation" *Id*.

V. The Commission Needs to Consider Fixed Fuel Price Inputs to the MPR

SB 1078 requires the Commission, in establishing the MPR, to consider "The long-term ownership, operating, and *fixed-price fuel costs* associated with *fixed-price* electricity from new generating facilities" (emphasis added). The MPR must, therefore, reflect the long-term *fixed* market price of electricity a utility would need to purchase to meet its capacity and energy needs from conventional fossil fuel resources instead of the renewable resources proposed under the RPS bidding process. As such, the Commission will use an appropriate methodology to develop a fixed fuel price input to the MPR over the varying contract terms. The difficulty comes in translating a mix of gas forward and forecast prices into long-term fixed prices as required by the RPS. During the workshops we will discuss the methodology for estimating this cost and developing robust data sources for gas forwards, swaps, and forecasts.

There are three primary fuel price parameters to consider: commodity price, hedge value (if any), and transportation costs. We discuss each below.

A. Commodity Price

Based on the legislative requirement to develop a long-term fixed market price of electricity, the most appropriate input parameter for the MPR would appear to be long-term forward, future, or swap gas contracts that would fix the price of gas in advance. We are aware, however, that forward markets for natural gas are (whether physical or financial) not particularly liquid. Natural gas futures can be purchased 6 years out through New York Mercantile Exchange (NYMEX), while over-the-counter financial swaps and forwards and fixed-price physical contracts are also available, but often not for lengthy durations. We invite comments on data sources for such long-term forward, future, and swap gas contracts, as well as information on the liquidity of these markets and the duration of contracts that are available.

We recognize the limited usefulness of the above instruments due to the long-term nature of RPS contracts (10 years or longer) and associated referents. As such, there may be a role for natural gas commodity price forecasts in developing the fixed fuel price inputs. Gas price forecasts are numerous and vary in their usefulness. We invite comments on sources for these forecasts, including CEC, Energy Information Administration (EIA), utility forecasts, and others. Parties should comment on whether and how forecasts not specific to California (e.g. EEA, EIA, Global Insight, PIRA) might need to be adjusted for use in the California market.

A key consideration in developing some hybrid of the above approaches is how to merge the limited data on gas forwards, futures, and swap contracts with the forecast data. Should forward data be used for at least the first 6 years from NYMEX, with forecast data used thereafter? How should the transition be made between the two? A number of parties have cited the Lawrence Berkeley National Laboratory (LBNL) report, which found that, at least over the last 5 years, forward prices for natural gas may have exceeded some published natural gas price forecasts. Participants should comment on whether this suggests that forecasted prices should be adjusted upwards to account for this recent empirical difference between forecasts and forwards.

B. Cost of Fuel Hedging and the Value of Renewables

D.03-06-071 states "We do not adopt a specific hedge value or methodology here, but we direct Collaborative Staff to use the best available methodology and data to calculate a gas hedge value for the relevant proxy plant" (p.22). Renewables are a physical hedge because they "physically reduce the demand for natural gas in [the] electric-power sector [which] has the effect of [reducing natural gas price volatility and] the price of gas" (Marcus/TURN, Tr. June 17, 2002, p.715). In addition, physical hedges provide an "external benefit to all of society [in] that the [overall] demand for [natural] gas is reduced" *(Id)*.

That is, if a utility entered into a long-term contract today with a conventional generator, on similar terms as it would with an equivalent long-term renewable resource contract, it would need to "lock in" a long-term price for fuel that "cushions" the utility from fluctuating fossil fuel prices. Renewables provide this cushioning effect from natural gas price risk. The MPR should reflect this value in addition to the cost of equivalent replacement capacity and energy.

Thus, the fuel cost for a proxy plant will not simply be just the forecasted cost of gas. Instead, it will be the forecasted cost of gas, plus the cost to hedge or lock-in those 10, 15, or 20-year fixed gas prices. In April 1, 2004 testimony, TURN (p.6) estimates such hedging costs at $0.50 to $0.80/MMBtu, whereas CEERT (p.II-19) expects a more narrow range of $0.50 to $0.52/MMBtu. TURN illustrates this premium in a brief illustrative example (p.16) over a 10-year period with an energy cost of $33/MWh and a hedge cost addition on top of that of $4.74/MWh. Thus, an MPR would be increased to a higher level (above the forecasted cost of gas) due to the addition of hedging costs necessary to lock-in such long-term prices.

C. Fuel Transportation Costs -- Basis Differentials

We now examine how the fixed fuel price input might take into account locational differences in gas prices. NYMEX gas future contracts are indexed to Henry Hub, while gas price forecasts may be estimating the cost of gas closer to ultimate delivery to a natural gas plant in California. Depending on the data sources used for the commodity portion of the cost above, we may need to estimate: (1) interstate transport cost to in-state delivery points, and (2) intrastate pipeline and distribution delivery costs. To account for transport costs, three general approaches (or combinations thereof) are possible: (1) use posted pipeline/distribution transport costs, (2) use NYMEX and Over-The-Counter (OTC) basis swaps to the extent available, and (3) use forecasts of transport costs/basis. Parties should comment on which of these general approaches would be best to estimate each of interstate and intrastate costs. Parties should, in tandem, comment on data sources and data availability.

As noted above in the discussion on locational-specific factors, D.03-06-071 gives preference to uniform, statewide values except where regionally differentiated values have already been developed. While the example given in D.03-06-071 relates to emissions offsets, we note here that fuel transport and delivery costs introduce another possible regional price difference. We invite participants to comment on whether the natural gas price input to the MPR is one of the items that should be regionally determined for each utility, and to provide appropriate data sources that meet the Commission's test of pre-existing regionally differentiated values, or whether a single estimate used for all utilities is appropriate.

Fuel transportation can be purchased on a firm (non-interruptible), or an interruptible basis, and some natural gas generators use a combination of non-interruptible and interruptible transport contracts, combined with the purchase of natural gas storage. The strategy of the natural gas generator depends in part on whether it plans to run in a baseload fashion (where the volume of gas purchases is relatively certain) or as a peaker (where volume is not clear). We may simply assume that the generator (whether baseload or peaking) purchases firm (non-interruptible) transport for its gas needs. However, we invite comments on whether this simplification is appropriate for the first-round solicitation, and whether interruptible transport contracts and storage costs should be considered in estimating the MPR. If so, parties should comment on the appropriate data sources and approaches to be used.

The MPR will reflect the value of two products: baseload and peaking resources. We noted above that fuel transport costs may differ between these two products. A peaking proxy plant resource would generally use gas during the summer months, when gas costs differ from the year-round average. Parties should comment on whether baseload and peaking resources should utilize gas commodity prices that reflect the different timing of gas usage, or whether use of annual averages is an acceptable approximation.

How frequently should the fuel price assessment be updated? It may be difficult to perform this analysis for each solicitation, especially where multiple solicitations occur each year. Updates will also depend on the data sources used and the frequency of their publication or availability. For example, NYMEX futures prices are totally observable, so could easily be updated for every solicitation. Gas forecasts might be harder to update with such frequency. Does an annual assessment capture changes and adjustments to market prices for gas, gas forecasts, futures contracts, and other gas pricing instruments? We initially recommend an annual or semi-annual update to the long-term gas price assessment. Parties should comment on this issue, with reference to each of the possible input components of the gas price.

VI. Which Data Sources for Long-Term Fixed Fuel Prices Should Be Used?

We invite parties to comment on which data sources are most reliable and cogent to the MPR, and which will require adjustment to account for California market differences.

- Derivatives: Gas forwards, futures, option, and swap contracts
- Gas forecasts
- Interstate transportation cost estimates
  - NYMEX basis swaps
  - OTC basis swaps
  - posted pipeline transport costs
  - forecasts of basis differences
  - past basis differences

- Intrastate transportation cost estimates
  - posted transport costs
  - forecasts of transport costs
  - other possible sources
  - Interruptible vs. firm contracts, and storage costs

VII. Proposed Process for Calculating & Disclosing MPRs

It is important to have an overview understanding of the process for calculating the six required MPRs. We present the following process for discussion:

1. Establish power plant proxy cost components, which have been provisionally set forth in Table 2 of this paper.

2. Collect input from parties on a long-term fuel price assessments. Collaborative staff (or the Commission) will confidentially establish fuel inputs to the MPR calculation. In order to maintain the necessary confidentiality of the MPR and avoid influencing the bidding process, the formula utilized by the Commission to develop the gas price component of the MPR may not be made public. Parties should comment on this proposed approach.

3. Staff computes MPRs that reflect an all-in market price for the appropriate contract lengths. At least six MPRs are needed – baseload and peaking MPRs for each of ten, fifteen, and twenty year contract lengths.

4. Disclosure of actual MPRs is not permitted until after the "closing date of a competitive solicitation, so as not to influence actual bid prices. This requirement is set forth as follows in Section 399.14(a)(2)(A):

   > Section 399.14(a)(2)(A) "A process for determining market prices pursuant to subdivision (c) of Section 399.15. The commission shall make specific determinations of market prices [MPRs] after the closing date of a competitive solicitation conducted by an electrical corporation for eligible renewable energy resources. In order to ensure that the market price [MPR] established by the commission pursuant to subdivision (c) of Section 399.15 does not influence the amount of a bid submitted through the competitive solicitation in a manner that would increase the amount ratepayers are obligated to pay for renewable energy, and in order to ensure that the bid price does not influence the establishment of the market price, the electrical corporation shall not transmit or share the results of any competitive solicitation for eligible renewable energy resources until the commission has established market prices [MPRs] pursuant to subdivision (c) of Section 399.15."

   Accordingly, the MPRs applicable to each bidding year will be made public at the end of the bid submission period.

VIII. *Appendix A -- Parties' January 2003 Filings on MPR Issues*

Comments filed on January 6, 2003 in R.01-10-024

MPR Issues Addressed:

1. CalWEA, California Wind Energy Association
2. CBEA California Biomass Energy Alliance
3. CEERT, Center for Energy Efficiency and Renewable Technologies
4. Green Power Institute
5. IEP, Independent Energy Producers
6. ORA, Office of Ratepayer Advocates
7. PG&E, Pacific Gas and Electric Company
8. SCE, Southern California Edison Company
9. SDG&E, San Diego Gas & Electric Company
10. TURN, The Utility Reform Network
11. UCS, Union of Concerned Scientists

Did Not Address MPR Issues:

12. CalSEIA, California Solar Energy Industries Association

Reply Comments filed on January 13, 2003 in R.01-10-024

MPR Issues Addressed:

1. CalWEA, California Wind Energy Association
2. CEERT, Center for Energy Efficiency and Renewable Technologies
3. IEP, Independent Energy Producers
4. ORA, Office of Ratepayer Advocates
5. PG&E, Pacific Gas and Electric Company
6. SCE, Southern California Edison Company
7. SDG&E, San Diego Gas & Electric Company
8. TURN, The Utility Reform Network

Did Not Address MPR Issues:

9. CalSEIA, California Solar Energy Industries Association
10. CBEA, California Biomass Energy Alliance
11. Chateau Energy, Inc.

IX. Appendix B -- Parties' April 2003 Testimony on MPR Issues

Parties' April 2003 Testimony on MPR Issues in R.01-10-024		
MPR Issues Addressed	**Parties Filing Testimony on April 1, 2003**	
Yes	CalWEA	California Wind Energy Association
Yes	CEERT	Center for Energy Efficiency and Renewable Technologies
Yes	Green Power	Green Power Institute
Yes	ORA	Office of Ratepayer Advocates
Yes (Ch.3, C. Hatton)	PG&E	Pacific Gas and Electric Company
Yes	Ridgewood	Ridgewood Olinda, LLC
Yes	SCE	Southern California Edison Company
Yes (F. Thomas)	SDG&E	San Diego Gas & Electric Company
Yes	Solargenix	Solargenix Energy, LLC (formerly Duke Solar)
Yes	TURN	The Utility Reform Network
Yes	UCS	Union of Concerned Scientists
Yes	Vulcan	Vulcan Power Company
No	CBEA	California Biomass Energy Alliance
No	Chateau	Chateau Energy, Inc.
No	IEP	Independent Energy Producers
No	ISO	California Independent System Operator